Service Date: May 27, 1982

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

IN THE MATTER of the Application of	)	
PACIFIC POWER & LIGHT COMPANY	)	UTILITY DIVISION
for Authority to Adopt New Rates and	)	
Charges for Electric Service Furnished	)	DOCKET NO. 81.8.70
in the State of Montana.	)	ORDER NO. 4881a

APPEARANCES

FOR THE APPLICANT:

C. Eugene Phillips, Murphy, Robinson, Heckathorn & Phillips, One Main Building, Kalispell, Montana 59901

George M. Galloway, Stoel, Rives, Boley, Fraser and Wyse, 900 S.W. Fifth Avenue, Portland, Oregon 97204

FOR THE PROTESTANT:

James C. Paine, Montana Consumer Counsel, 34 West Sixth Avenue, Helena, Montana 59620

John Allen, Consumer Counsel Staff Attorney, 34 West Sixth Avenue, Helena, Montana 59620

FOR THE INTERVENOR:

Phil Strope, Attorney at Law, 501 North Sanders, Helena, Montana, appearing on behalf of the Outlaw Inn, Perkins Cake & Steak, and the Montana Innkeepers' Association.

FOR THE COMMISSION:

Calvin K. Simshaw, Staff Attorney

BEFORE:

GORDON E. BOLLINGER, Chairman
JOHN B. DRISCOLL, Commissioner
HOWARD L. ELLIS, Commissioner
CLYDE JARVIS, Commissioner

THOMAS J. SCHNEIDER, Commissioner

FINDINGS OF FACT

A. GENERAL

1. The Pacific Power and Light Company (PP&L or Applicant) is a public utility furnishing electric service to consumers in the State of Montana.

2. Applicant's petition, filed August 28, 1981, requests this Commission's approval of rates and charges for electric service which are designed to produce an increase in annual gross operating revenues of $6,435,000 based on a test period of 12 months ended December 31, 1980.

3. On September 10, 1981, the Commission issued a memorandum which contained a proposed procedural schedule. On September 28, 1981, the Commission issued a procedural order.

4. The Direct Service Industrial Customers ("DSI's") filed for intervention on December 16, 1981. The Commission granted this intervention at its regularly scheduled agenda meeting on December 21, 1981.

5. The Montana Consumer Counsel (MCC) has participated in this Docket on behalf of the consuming public since the inception of these proceedings.

6. On December 3, 1981 the Applicant filed a motion to introduce supplemental testimony required by the passage of the Economic Recovery Tax Act of 1981. On December 8, 1981 the Commission granted the Applicant's request to file supplemental testimony and approved revisions to the procedural schedule.

7. November 6, 1981 was set as the final day for interested parties to file Petitions to Intervene.

8. November 20, 1981 was the final day for completion by PP&L of all answers and responses to discovery and data requests directed to PP&L by other parties (except for the supplemental testimony on ERTA).

9. December 11, 1981, was the final day for completion and service upon PP&L and other parties of the prepared testimony and exhibits of all parties except PP&L (excluding testimony on ERTA). George Hess was granted an extension of time to December 16, 1981 by the Commission. December 11, 1981 was also the final day for filing by all parties of a position statement specifying the positions to be taken in the case.

10. December 21, 1981 was the final day for parties other than Applicant to make data requests to the Applicant related to the supplemental prepared testimony and exhibits.

11. December 28, 1981 was the final day for discovery and data requests to all parties by PP&L. The Commission granted a five day extension on data requests to George Hess. December 28, 1981 was also the final day for intervenor data requests to parties other than PP&L.

12. January 4, 1982 was the final day for the Applicant to respond to data requests related to the supplemental testimony and exhibits.

13. January 11, 1982 was the final day for completion of answers by all parties other than PP&L to discovery and data requests made pursuant to number 11.

14. January 18, 1982 was the final day for parties other than the Applicant to file supplemental testimony and exhibits related to the Economic Recovery Tax Act of 1981.

15. January 25, 1982 was the final day for service of rebuttal testimony by PP&L.

16. February 1, 1982 was the final day for any party which intends to introduce as evidence, data requests or other discovery as part of its basic case, to notify all parties of the specific data requests or other discovery it plans to so introduce.

17. February 9, 1982 is the opening day of hearing in this Docket.

B. CAPITAL STRUCTURE AND ASSOCIATED COSTS

18. Applicant proposed the following capital structure and associated costs (Table 2-12):

Type	Capital Structure	Cost	Weighted Cost
Long-Term Debt	52.7%	9.26%	4.88%
Preferred Stock	9.8	9.94	0.97
Deferred Taxes	2.4	--	--
Common Equity	35.1	16.25	5.70
	100.0%		11.55%

19. MCC proposed the following capital structure and associated costs (CMS-1):

Capital Weighted

Type	Structure	Cost	Cost
Long-Term Debt	55.4%	9.26%	5.13%
Preferred Stock	13.8	9.94	1.37
Common Equity	30.8	14.50	4.47
	100.0%		10.97%

Applicant's Presentation

20. Applicant proposed to utilize its target ratios in the capital structure, adjusted to reflect the addition of deferred taxes amounting to 2.4 percent of the capital structure. The Applicant's target ratios are: 54 percent long-term debt, 10 percent preferred stock, and 36 percent common equity (Exh. PPL-2, p. 4).

MCC's Presentation

21. MCC does not include deferred taxes in the capital structure. This is consistent with Mr. Hess' recommendation to deduct deferred taxes from rate base (Exh. MCC-3, pp. 6-7). The Commission, in previous decisions, has consistently disallowed deferred taxes in rate base, primarily because deferred taxes do not affect the overall cost of capital.

22. Dr. Smith also adjusted the common equity to eliminate the portion invested in subsidiaries other than the electric utility operations (Exh. MCC-7, p. 55). MCC argues that debt is dedicated to the utility and does not support nonutility operations.

23. This present Docket contains a proposal concerning subsidiaries as they pertain to the capital structure. In the PP&L system, the use of parent debt to finance subsidiary investments does not occur until the second tier of the system is reached, as described in MCC's testimony in Docket No. 81.8.69. MCC's capital structure proposal in this case reflects the different financing techniques used throughout the PP&L system (MCC Reply Brief, p. 13). Mr. Lanz' capital structure includes all of PP&L's consolidated capital, except for the subsidiary debt.

> Under Mr. Lanz' approach, if the subsidiaries earn an equity return on the equity capital investment of PP&L, as recorded on its books of account, then the overall consolidated equity return will exceed the estimated consolidated cost of equity capital and the Company will have derived a windfall at the expense of utility ratepayers whose debt capital has been improperly attributed to subsidiary operations.
> (Exh. MCC-7, p. 60)

24. In establishing PP&L's utility capital structure, MCC removed both the subsidiary debt and subsidiary equity capital from the consolidated capital structure and assigned them directly to those operations. This same approach was adopted by the Commission in Docket No. 80.8.67. MCC maintains that failure to reduce the equity capital of the consolidated enterprise by the investment in its subsidiaries results in an excess return to the enterprise (MCC Initial Brief, p. 25).

25. The Commission concurs with the arguments set forth by Consumer Counsel such that debt is dedicated to the utility and does not support nonutility operations. Thus, components of the capital structure which are related to nonutility subsidiaries must be eliminated. The Commission finds the capital structure proposed by Dr. Smith to be appropriate in this Docket.

Cost of Debt

26. The debt capital is not a contested issue in this case. The cost of long-term debt is based on the embedded debt cost at November 30, 1981, and has been determined to be 9.26 percent by both MCC and the Applicant (Tr. p. 695). This cost is acceptable to the Commission.

Cost of Preferred

27. The cost of preferred stock is not a controverted issue in this case. The cost of preferred stock is based on the embedded cost of preferred shares outstanding at November 30, 1981, and has been determined to be 9.94 percent by the Applicant and MCC (Tr. pp. 695-696) . This cost is acceptable to the Commission.

Cost of Common Equity

28. Applicant uses the following methodologies in arriving at a return on equity of 16.25 percent:

a. Application of the Pacific Model (Applicant's Mathematical Model) to the Applicant's financial data. The Model yielded a range of return on equity of 15.38 percent to 16.47 percent.

1. The dividend payout ratio was estimated to be approximately 75 percent, based on the average historical payout ratio for the Applicant over the eleven-year period 1970 through 1980 (Exh. PPL-2, p. 11).

2. Net proceeds to market price averaged 95.7 percent on all electric operating utilities issuing common stock from 1978 through 1980 (Exh. PPL-2, Table 2-6).

3. Annual growth in common equity was estimated to be 10 percent. This estimation was derived by reviewing data on growth in net utility plant for the years 1962 through 1980, as Applicant testified that growth in net utility plant is a good indicator of growth in common equity capital (Exh. PPL-2, p. 12).

4. The investors discount rate was calculated to be plus or minus 2 percent. Mr. Lanz used plus 2 percent to account for near-term changes in market conditions (Exh. PPL-2, p. 13).

5. Future dividend growth was estimated to be 4.6 percent. This estimation was made after reviewing data on compound growth in the Applicant's dividends per share over twelve different periods, each ending in 1980 (Exh. PPL-2, p. 14).

6. An estimate of the dividend yield was developed by reviewing the Applicant's historical dividend yields, Moody's 24 utility composite historical dividend yields, and a historical series of 91-day treasury bill bids late-1981 and early 1982. The Applicant's dividend yield was estimated to be 10.6 percent (Exh. PPL-2, pp. 15-17).

b. The Pacific Model's reliability was tested on six companies which the Applicant feels have investment opportunities similar to that of the Applicant. The selected companies had March, 1975 through March, 1981 growth in dividends per share plus March, 1980 dividend yield between 14.10 percent and 15.10 percent (Exh. PPL-2, pp. 18-18).

29. MCC uses the following methodologies in arriving at a return on equity of 14.5 percent:

a. Application of discounted cash flow (DCF) techniques to Applicant's financial data. The DCF methodology yielded a range of return on equity of 14 to 15 percent.

1. Dividend yields for 95 electric and combination electric and gas utilities traded on the New York Stock Exchange were calculated on a pre-Three Mile Island basis and an updated September, 1980 basis. The dividend yields were calculated on the basis of an average price. The pre-TMI yield was found to be 9.5 percent, the 1980 dividend yield was 11.5 percent (Exh. CC-7, Appendix B, p. 2).

2. Expected dividend growth was calculated by examining growth rates in dividends, earnings and book value over a ten year period for the companies in the study. The weighted average growth for these companies was 3.3 percent in the pre-TMI period and 3 percent for the more recent period (Exh. CC-7, Appendix B, p. 4).

3. The model used by MCC was used to identify differences between the cost of equity for the Applicant and the industry as a whole.

b. The reasonableness of the DCF approach was examined by performing a comparable earnings study. A tabulation of earned rates of return for 95 electric and combination utility companies indicated that average earnings on equity for the 1970-1980 period were in the 11 percent to 12-plus percent range (Exh. CC-7, p. 40).

30. MCC arrived at a rate of return on equity of 14.5 percent. During the hearing, however, Dr. Smith testified to the following:

> ...My numbers have gone up to some extent; and if the Commission were to adopt a number as high as 14.75 percent, I don't think that that would be a mistake. I'm leaving my recommendation at 14.5, but again, noting that it's a range of 14 to 15, and the Commission may want to go a little bit higher than the middle point of the range. (Tr., pp. 698-699)

31. Changing the equity rate of return from 14.5 percent to 14.75 percent has the effect of raising the weighted cost of equity from 4.47 percent to 4.54 percent and raising the overall weighted cost of capital from 10.97 percent to 11.04 percent. During the hearing Dr. Smith testified, "...I believe a return allowance of about 11 percent would be reasonable." (Tr. p. 697)

32. Both MCC and the Applicant used a DCF model to determine the cost of equity in this proceeding. In each model there are elements which are based upon the judgment of the particular witness. Upon viewing the two models presented, the major difference appears to be the use of a large number of companies for analytical purposes in the MCC proposal (95), while the Applicant relies on the Pacific Model (6 companies) to estimate the cost of equity for Pacific Power and Light. Of the two methods, the Commission prefers the MCC approach as it, through the process of evaluating many companies, eliminates factors which are unique to a particular firm.

33. Concerning the Cost of Common Equity, the Applicant recommends 16.25 percent return and MCC proposes 14.75 percent return on equity. The Commission emphasizes the following points in determining the proper equity return figure:

1. The cost of capital has been quite high recently and has generally risen over the past year due to prevailing economic conditions.
2. Pacific Power and Light has been actively encouraging conservation efforts and programs as part of corporate policy.

34. The Commission having considered the above factors, determines that the acceptable rate of return on common equity is 15 percent. This corresponds with the upper end of the range recommended by Dr. Smith.

Rate of Return

35. Based on the findings for long-term debt, preferred stock, and common equity, the following capital structure and costs are determined appropriate:

Type	Capital Structure	Cost	Weighted Cost
Long-Term Debt	55.4%	9.26%	5.13%
Preferred Stock	13.8	9.94	1.37

Common Equity	30.8	15.00	4.62
Overall Cost of Capital	100.0%		11.12%

C. RATE BASE

36. The following rate base proposals were submitted. The final column is the rate base approved by the Commission.

1980 Test Year
(000)

	Applicant 1981 Year-End Rate Base	Adj. by MCC	MCC Average Rate Base	Commission Approved Rate Base
Net Plant in Service	$70,898	$ (4,501)	$66,397	$66,397
Plant held for Future Use	104	(42)	62	62
Acquisition Adjustment	1	(1)	--	--
Nuclear Fuel	11	13	24	24
Customer Advances for Construction	(293)	(3)	(296)	(296)
Materials and Supplies	1,509	(215)	1,294	1,294
Cash Working Capital	527	--	527	527
Extraordinary Property Losses	12	11	23	23
Unamortized Leasehold Improv., etc.	353	(27)	326	326
Weatherization-Interest Free Loans	380	(155)	225	225
Customer Contributed Capital	--	(1,853)	(1,853)	(1,853)
Unamortized Investment Tax Credits	--	(194)	(194)	(232)
Sale of Malin-Midpoint Tax Deductions		(1,164)	(1,164)	(1,164)
Total Rate Base	$73,502	$ (8,131)	$65,371	$65,333

37. The initial controverted issue centers around the methodology used to figure the rate base. The Company's filing was based on a year-end 1981 rate base. The Company maintains that in the past it has failed to earn a fair rate of return, and it will have no reasonable opportunity to do so in the future if the rates are based on a 1980 test period.

> Quite simply, the policy of using a historical test period, without proper consideration for cost increases which will not be offset by

> incremental revenues during the period in which the rates will be in effect, has resulted in the Company not being given a reasonable opportunity to achieve its authorized return on investment. Due to this problem, the Company has selected a test period adjusted for the changes to which I have previously testified for use in establishing its proposed rate levels as a method to be used in partially mitigating the problem. The use of such a test period, whereby costs are established at a level which more closely approximates the costs which will be incurred during the period in which the rates will be in effect will allow the Company a better opportunity to achieve the return authorized in these proceedings. (PP&L Exh. No. 4, PP. 3-4)

38. MCC proposes a 1980 average rate base, adjusted to include certain known and measurable 1981 changes. Mr. Hess included in the 1980 rate base "the Malin/Midpoint transmission line that went into service in November, 1981 and the new mining equipment added in 1981 at the Centralia and Dave Johnston mines. Those 1981 additions substantially increase rate base but produce little additional net income." (MCC Exh. No. 3, p. 4)

39. Mr. Hess disagreed with the use of year-end 1981 rate base in the following testimony:

> ...Insofar as PP&L's adjustment to year-end 1981 in this case is concerned, it was particularly speculative because it was prepared before the end of 1981, and is not based on actual figures. I think that if you take the test year in conjunction with the Commission's interim rate relief policy, it would be particularly inappropriate to make adjustments beyond the time when that interim relief is going to be granted. In other words, I do not believe that the rate payer should start paying for a cost increase before it has taken place. ...I would like to see PP&L file on a timely basis, make adjustments for all known changes that might occur up to the time the interim rate relief might be expected, and then ask for and get interim rate relief. That way we are dealing with known changes, and we are dealing with revenue expense, rate base relationships that are current, as of the time the interim rates will go into effect. (Tr. pp. 439-440)

40. One of the primary considerations of the Commission in rate base decisions has always been proper matching of test year income with the plant that produced that income. The Commission, therefore, determines in favor of the MCC proposal of a 1980 average rate base, adjusted for certain known and measurable 1981 changes.

Net Plant in Service

41. MCC witness Hess made net adjustments for Net Plant in Service in the amount of $4,501,000. Some of these adjustments serve to "reverse the Company's adjustments to reflect the year-end level of...rate base other than the 1981 additions to the Centralia and Dave Johnston mines" (MCC Exh. No. 3, p. 5), which were included in rate base as known and measurable changes. Concerning his Malin/Midpoint transmission line adjustment, Mr. Hess said the following:

> I should note that the Company included the Malin/Midpoint transmission line in a separate adjustment which I have accepted. Consequently, that 1981 addition is included in my recommended rate base. ...Exhibit 4 includes the Malin/Midpoint transmission line at an estimated cost of $185,088,000. In response to my data request No. 2 the Company provided a revised estimate for this line of $193,562,000. The adjustments in column D reflect the higher revised estimated cost. (MCC Exh. No. 3, pp. 5 and 7)

42. The Commission determines that the aforementioned MCC adjustments which reflect 1980 average year rate base and include the Malin/Midpoint transmission line and known and measurable 1981 additions to the Centralia and Dave Johnston mines are accepted. These figures comply with the accepted methodology of average year rate base. The adjustments are in the amount of $4,501,000, leaving the amount of $66,397,000 to be the proper amount of Net Plant in Service included in rate base.

Plant Held for Future Use

43. The Company's proposed rate base included $104,000 of plant held for future use. MCC proposed an adjustment to remove $42,000 of this amount as the property is not expected to be placed in service prior to the period 1990 to 2000. Current ratepayers should not be burdened with carrying costs of property which will not be used in the imminent future. The Commission finds the MCC adjustment to be correct, leaving the amount of $62,000 as the proper amount of Plant Held for Future Use included in rate base.

Acquisition Adjustment

44. Applicant's proposed rate base included an acquisition adjustment in the amount of $1,000. MCC proposed to eliminate this amount as this figure represents the amount paid for property in excess of its original cost. Removal of this acquisition adjustment is consistent with past Commission action. The Commission finds that the $1,000 acquisition adjustment should be eliminated.

Nuclear Fuel

45. MCC reversed the Company's adjustments reflecting the 1980 year-end level of nuclear fuel and then restated this item to its 1980 average level. The Commission agrees with these adjustments as they reflect the preferred rate base methodology. The proper amount of Nuclear Fuel included in rate base is $24,000.

Customer Advances For Construction

46. MCC reversed the Company's adjustments reflecting the 1980 year-end level of customer advances for construction to their 1980 average level. MCC also reversed the Company's adjustments reflecting 1981 year-end levels. The Commission agrees with these adjustments as they reflect the preferred rate base methodology. The correct amount of Customer Advances for Construction deducted from rate base is $296,000.

Materials and Supplies

47. MCC reversed PP&L's adjustments reflecting the 1980 year-end level of materials and supplies to their 1980 average level. The Commission agrees with these adjustments as they reflect the preferred rate base methodology. The proper amount for Materials and Supplies included in rate base is $1,294,000.

Cash Working Capital

48. "...The development of net cash working capital supplied by investors, as assigned and allocated to Montana, is based on a lead lag study performed by the Company for the 1980 test period." (PP&L Exh. No. 4, p. 18) MCC made no adjustment to the Company figure. The

Commission finds that the proper amount of Cash Working Capital to be included in rate base is $527,000.

Extraordinary Property Losses

49. MCC reversed the Company's adjustments reflecting the 1980 year-end level of extraordinary property losses. MCC also adjusted the Applicant's figures to restate them to their 1980 average level. The Commission finds these adjustments are proper and that they reflect the preferred rate base methodology of average year rate base. The proper amount of Extraordinary Property Losses included in rate base is $23,000.

Unamortized Leasehold Improvements, Etc.

50. MCC reversed the Company's adjustments reflecting the 1980 year-end level of unamortized leasehold improvements, etc., to their 1980 average level. MCC also reversed the Company's adjustments reflecting 1981 year-end levels. The Commission agrees with these adjustments as they reflect the preferred rate base methodology. The proper amount of Unamortized Leasehold Improvements, etc., included in rate base is $326,000.

Weatherization-Interest Free Loans

51. MCC reversed the Company's adjustments reflecting the 1980 year-end level of Weatherization-interest free loans and then restated this item to its 1980 average level. The Commission agrees with these adjustments as they reflect the preferred rate base methodology. The proper amount of Weatherization-Interest Free Loans included in rate base is $225,000.

Customer-Contributed Capital

52. The Applicant proposed to include deferred taxes at zero cost in the cost of capital and include these customer contributed funds in rate base. MCC proposed to eliminate the deferrals from rate base.

> ...The average accumulated deferred income taxes and unamortized deferred investment tax credits represent amounts collected from

> customers through rates charged in the past in excess of taxes actually paid. (MCC Exh. No. 3, p. 6)

MCC also made an adjustment which "provides deferred federal income taxes for the difference between ACRS depreciation and book depreciation on 1981 property." (MCC Exh. No. 3, p. 9)

53. The Commission, consistent with prior decisions, finds the removal of deferred taxes from rate base to be correct. The proper amount of Customer-Contributed Capital deducted from rate base is $1,853,000.

Sale of Malin-Midpoint Tax Deductions

54. The Economic Recovery Tax Act of 1981 allows the owner of equipment in use to transfer the resulting Investment Tax Credits (ITC) to a qualified taxpayer in exchange for a cash payment. Such a transaction is described as a "safe harbor lease." The Company entered into such an arrangement with Standard Oil Company of Indiana in December of 1981. (PP&L Exh. 19-T, p. 24)

55. For ratemaking purposes, MCC witness Hess recommended that "the proceeds be amortized above the net operating revenue line and that the unamortized balance be deducted from rate base." (MCC Exh. No. 4, pp. 1-2) Mr. Hess continued to comment:

> About $14.3 million of the tax deductions sold are investment tax credits and I recommend that amount be amortized over a relatively short period to reflect PP&L's election to flow through tax reductions resulting from investment tax credits. The remainder of the proceeds I would amortize over the thirty-year life of the lease, but not on a straight-line basis. The tax reductions associated with PP&L's lease payments less interest income are small in the early years and very large toward the end of the lease's life. ...To more equally benefit all customers over the term of the lease, the tax benefits should be spread more uniformly over the life of the lease, and, therefore, the amortization of the proceeds from the sale of the tax benefits should be greater in the early years and taper off in the later years when the tax reductions from the lease payments increase. (MCC Exh. No. 4, p. 2)

56. Mr. Hess accordingly adjusted his figures and tables in MCC Exhibit No. 3 to reflect the effect of the sale on the overall revenue requirements. These adjustments are shown in the exhibits of his Supplementary Testimony.

57. The Company's witness, Mr. Watson, strongly protested MCC's approach to this issue. Watson felt that U.S. Treasury officials would be highly concerned relative to the "negative tax policy consequences of the potential flow through to ratepayers of the cash payment received by utilities as a result of a safe-harbor lease: ...because not only would the lessor realize the tax benefits and reduce its taxable income, but the utility's taxable income would also be reduced as a result of lower authorized revenues." (PP&L Exh. No. 19-T, p. 27).

58. Mr. Watson further elaborated concerning the proposed treatment by Mr. Hess:

> The proposed treatment of an ITC component through a five-year amortization to operating income, is inconsistent with the treatment of ITC generated and utilized by the Company with respect to pre-1981 utility property and is inconsistent with ERTA requirements for investment tax credit treatment. ...Mr. Hess misses the point on two counts. First, with respect to pre-1981 ITC the Company has elected to use an eight-year amortization, not a five-year amortization as Mr. Hess proposes. Second, and most important, the flow-through option does not exist with regard to post-1980 property such as the Malin-Midpoint line. Therefore, Mr. Hess's adjustment to his perceived ITC value not only defeats the purpose of ERTA but also is based on unsound logic. ...His suggested flow through treatment could destroy the benefits of this transaction and require the Company to return the cash it received plus pay an interest penalty on the returned amount. Generally, the economic benefits of the safe-harbor lease alternative for the Company could be precluded to the extent that regulatory treatment makes such an arrangement unattractive. ...If this Commission adopted Mr. Hess's proposed ratemaking approach, the Company would be severely impacted as to the economics of the transaction, a principle intent of ERTA would be thwarted, and the Company would be penalized for attempting to reduce the long run costs to its ratepayers. (PP&L Exh. No. 19-T, pp. 29-32)

59. After reviewing the evidence brought forward in this Docket, the Commission determines that the aforementioned "safe harbor lease" will be treated as a sale of utility assets for ratemaking purposes. The Commission, therefore finds in favor of the Hess approach, and this order

will reflect MCC's various adjustments relative to this sale of tax deductions. The proper amount of rate base reduction from the sale of Malin-Midpoint tax deductions is $1,164,000.

Unamortized Investment Tax Credits

60. MCC proposed a "flow-through of one-half of the investment tax credits that can be utilized in the test year after adjustment for any rate increase authorized." (MCC Exh. No. 3, p. 11) The Commission, consistent with prior decisions, finds that unamortized investment tax credits are properly deducted from rate base. Based upon an adjustment in the rate base and the revenues and expenses sections, the amount of tax credits to be deducted is increased. In order to achieve an average adjustment, one-half of the net expense adjustment is deducted from rate base. The proper amount of Unamortized Investment Tax Credits deducted from rate base is $232,000.

Total Rate Base

61. As a result of the various adjustments, the Commission finds the proper amount of total 1980 average rate base, adjusted for known and measurable changes, to be $65,333,000.

D. REVENUES, EXPENSES, AND REVENUE REQUIREMENT

62. Mr. James T. Watson sponsored exhibits and testimony which detailed the cost of service and rate base amounts which support the revenue increase of $6,435,000 requested by the Applicant. Mr. Watson presented evidence on the financial condition of the Applicant with some emphasis on the adverse effects of inflation and inadequate rate relief. He indicated that the Company utilized a 1980 historical test period as a basis for its filing and made various 1981 adjustments. Mr. Watson stated that these adjustments are consistent with the Commission's Minimum Rate Case Filing Standards which allow a utility to include adjustments which will become effective within 12 months of the last month of the historical test period. Mr. Watson concluded that, based on the test period end December 31, 1980, the Company would require additional revenues of $6,435,000 in order to earn an overall return of 11.55 percent.

63. Mr. George F. Hess, a witness for MCC, presented testimony and exhibits on the cost of service and the proper rate base. Mr. Hess urged the use of an average 1980 rate base, adjusted

for certain known and measurable 1981 changes. Mr. Hess prepared a series of schedules and presented related testimony which culminates with the change in revenues required to produce the 10.9 percent rate of return recommended by Dr. Smith. Mr. Hess concluded that, based on the 1980 average test year, the Company requires additional permanent revenues of $2,465,000.

Operating Revenues

64. MCC witness Hess made two adjustments to operating revenues, both of which related to his recommendation that the Commission adopt a 1980 average rate base rather than a year-end 1981 rate base as proposed by PP&L. In column A of Schedule 2, p. 1 of 2, Hess increased revenues by $22,000 to reflect revenues based upon an average rate base. In column B of that same schedule Hess decreased revenues by ($76,000) to eliminate the 1981 year-end level of customers and rate base. For the reasons stated in the rate base section of this order these adjustments are accepted by the Commission.

65. Company witness Watson indicated during cross-examination that approximately $15,000,000 of utility investment tax credits have been transferred to nonutility operations. (Tr. p. 137) This transfer has been made due to the fact that there has not been sufficient utility income to utilize these investment tax credits. Watson indicated that these credits will be passed back to the utility if the income picture improves. The practical effect of the treatment adopted by PP&L is a large loan from utility to nonutility operations at zero interest. Investment tax credits which are generated by utility property are utility assets. Currently the electric utility receives no benefit from this transfer, which requires an adjustment by the Commission. Since investment tax credits are being loaned to nonutility operations, the electric utility is entitled to earn interest on the transfer. The Commission finds that the overall rate of return granted in this case is the interest which shall be earned on the transfer of investment tax credits. This adjustment increases revenues by $49,000 ($15,000,000 X 11.12% X .029373). The above adjustments to revenue result in present revenues of $21,185,000.

Expenses Associated With 1981 Year-End Rate Base

66. As was noted in the rate base section of this order, PP&L proposed a 1981 year-end rate base while MCC advocated a 1980 average rate base. Hess in making adjustments to reflect a 1980 average rate base reduced operating expenses by ($32,000), depreciation and amortization by ($146,000) and taxes other than income by ($192,000). As a result of the Commission determination that the appropriate test period included a 1980 average rate base, these adjustments are accepted.

Malin/Midpoint Transmission Line

67. In response to Hess Data Request No. 2, PP&L indicated that the cost of the Malin/Midpoint line had increased. Hess increased depreciation and amortization by $6,000 and taxes other than income by $3,000. The Commission accepts these adjustments for increased expenses.

Miscellaneous Expenses

68. MCC witness Hess increased pension and insurance costs to reflect higher costs revealed in response to his data request No. 1. Postal expenses were increased to reflect the recent postal rate increase. In addition, Hess eliminated institutional advertising and the Company's adjustment for EEI research and dues. These adjustments taken as a group increase operating expenses by $16,000. All of these adjustments are consistent with past Commission decisions, and are acceptable to the Commission.

Deferred Income Taxes

69. In his original testimony MCC witness Hess increased deferred income taxes by $224,000. The reason for the adjustment was explained by Hess:

> Mr. Watson points out in supplemental testimony that for a utility to qualify for the use of the Accelerated Cost Recovery System (ACRS) provided in the 1981 Economic Recovery Tax Act it must be allowed to normalize for the difference between ACRS and book depreciation. (Direct, p. 9)

However, after PP&L sold the tax benefits associated with the Malin/Midpoint Line, Hess reduced his original adjustment by ($205,000). This results in a net increase in deferred income tax expense of $19,000. As a result of the sale of the Malin/Midpoint tax benefits the Commission finds that deferred income taxes should be increased by $19,000.

<u>Captive Coal</u>

70. MCC witness, Dr. J. W. Wilson, proposed an adjustment to eliminate the profit from Jim Bridger Coal which exceeded a rate of return of 16 percent. Dr. Wilson calculated that in 1980 the Bridger Coal Mining Joint Venture had an equity return of approximately 60 percent and the total return (equity plus debt) realized by PP&L's subsidiary (Pacific Minerals, a subsidiary of NERCO) was approximately 37 percent. (Exh. MCC-5, p. 23)

71. Dr. Wilson judged these profits as "extraordinary" and based his conclusions on three studies. First, he examined recent and projected rates of return for the three independent coal companies for which he obtained public financial data. Second, he examined the return being earned by PP&L on its other coal mining companies which do not have captive market transactions with the Company's own electric generating plants. Third, Dr. Wilson performed a study of profit rates earned by unregulated firms throughout the industrial sector of the U.S. economy. (Exh. MCC-5, pp. 26-27)

72. The results of all three of Dr. Wilson's studies indicated that a proper rate of return for the Bridger Operation would be between 15 and 16 percent. The related captive coal adjustment reflects what Dr. Wilson professes to be a reasonable rate of return for the Bridger Coal Company based on his "rate of return" methodology.

73. The Company's methodology concerning the captive coal issue was the "market price" approach. Mr. Watson and Mr. Grundmann presented evidence that an independent, competitive coal market exists on which Pacific could have procured coal in lieu of entering into the Bridger contract, and that the terms of the Bridger contract, and the price paid pursuant to it, compare favorably with what would have been available on the open market. (Exh. PP&L 4-T, pp. 9-10; 21-T, p. 11)

74. Mr. Watson drew the following conclusions:

> (1) Bridger's contract price for coal sold to the Company in 1981 was more favorable to electric ratepayers than 25 of the 26 other supply arrangements for which data was available for 1981, both on the basis

> of cost per ton and cents per million Btu; (2) Bridger's contract price amounted to 71 cents per million Btu delivered, compared to an average price, FOB mine, for the other 26 sales during 1981 of 118 cents per million Btu. The average cents per million Btu associated with other long-term coal sales made from January through April, 1981, from the Montana and Wyoming coal region is approximately 1.7 times the price charged the Company for coal deliveries made from the Bridger Coal Company. (Exh. PP&L 4-T, pp. 9-10)

75. Mr. Grundmann analyzed the Bridger coal contract and concluded that not only did it appear to be the product of arms'-length negotiations, but if anything, it was slightly more favorable to the utility purchaser than typically would be the case. (Exh. PP&L 21-T, pp. 13 and 29) With regard to a comparison of the average delivered price of coal from other Montana and Wyoming sites, Mr. Grundmann determined the following:

> First, that the average delivered price of all of the proposals is over twice (206 percent) the actual price for the Bridger Contract, and any individual proposal is more than 71 percent greater. Second, even if a comparison were to be made on a mine-mouth basis (which I do not believe is appropriate...), the average FOB mine price of all of the proposals is over 35 percent higher than the actual price for the Bridger Coal Contract. (Exh. PP&L 21-T, p. 31)

76. The Company attacked Dr. Wilson's adjustment (and rate of return methodology in general) on three main fronts: (1) interpretation of the Montana Supreme Court's decision in <u>Montana-Dakota</u> <u>Utilities</u> <u>Co.</u> <u>v.</u> <u>Bollinger</u>, 632 P.2d 1086 (Mont. 1981); (2) lack of available comparable data, and (3) flaws in the manner in which Dr. Wilson calculates a rate of return for the Bridger Mine. (PP&L Exh. No. 19-T, p. 2)

77. In making this decision, the Commission found weaknesses in both approaches used to determine the captive coal expense. The Company's "market approach" was fairly thorough. However, as explained on page 41 in Order No. 4714a of Docket No. 80.4.2, from the Department of Justice report "Competition in the Coal Industry":

> In practice, however, because of the nature of the coal markets, <u>identification of the appropriate competitive prices is virtually impossible</u>. Coal prices are not some broad national aggregate but are tied to very specific location and quality factors. In addition, a significant portion of the steam coal is sold by long-term contract.

> Thus it may prove difficult to estimate an appropriate set of market prices to use to check a utility's accounting price of coal. (emphasis added) (Tr. pp. 47 & 48 of Docket No. 80.4.2)

For example, concerning the use of Montana coal compared to Bridger coal, Company witness Grundmann said the following in response to questions by Commissioner Schneider:

> Q. To the extent that Pacific Power and Light could use Montana coal, there would be either a major transmission line involved, or transportation involved?
>
> A. Yes, sir.
>
> Q. Would you agree with me that, given those major cost components, Montana coal is virtually outside their reach?
>
> A. Montana coal would be economically disadvantageous.
>
> Q. Particularly, vis-a-vis Bridger or one of their other areas?
>
> A. Yeah, because you're talking about a considerable distance there, and it would be very economically disadvantageous. I don't usually say "never say never," <u>but it would be very tough for it to be competitive</u>. There could be characteristics of coal, combination of environmental conflicts--there are a number of things that go into making a decision in what is the most economic lifetime busball cost of electricity from a given plant, but it would be hard for it to overcome the economic disadvantages. (emphasis added) (Tr. pp. 534-535)

Mr. Grundmann's testimony points to a very prominent weakness in the market approach. Coal from outside areas of the generating units require varying degrees of transportation and related costs which can greatly distort the comparability of using shipped coal versus a minemouth operation. Although the market may show the economic advantage of a minemouth operation, the relative comparability of the coal prices may be forfeited because of inordinate, dissimilar costs such as transportation.

78. Dr. Wilson's "rate of return method" should have provided highly useful guidelines for determining a reasonable level of profitability for Bridger Coal Company. However, it is not clear from this record that MCC's determination of Bridger's overall return was consistent with the process used to determine the rate of return for the three available coal companies or the unregulated firms

throughout the economy. Therefore, the Commission finds Dr. Wilson's proposed coal adjustment to be unacceptable in this Docket.

79. Mr. Watson, on page 5 of his Rebuttal Testimony, used the figure $318,000 as the amount of MCC disallowance. MCC also used this figure on page 10 of their Initial Brief. Commission Staff, however, discovered through calculation and investigation that the $318,000 figure was based on a unit coal price of $14.504 as provided by the Company on page 210 of Book 5. This $14.504 figure includes a 4.5 percent inflation factor which was added by Mr. Watson to the actual coal price of $13.879 per unit. The Staff eliminated the inflation factor to arrive at the unaccepted Wilson adjustment of $236,000. Correspondingly, there will be an adjustment of $82,000 incorporated as a decrease of Company coal expense to reflect the disallowance of inflation in the final coal expense figure.

80. The Commission stresses that this decision in no way determines a preference between the two methodologies in question, but rather, reflects the evidence presented in this particular case. As pronounced in the MDU v. Bollinger court case, the Commission reserves the right to determine the appropriate methodology for captive coal expenses.

Coal Expense

81. MCC witness, Hess, made an adjustment for coal costs in the amount of $429,000, including Dr. Wilson's captive coal adjustment of $236,000. These adjustments addressed two elements of the Company's computations: (1) inflation; and (2) annual average cost. Of the Applicant's four coal-fired generating stations, Mr. Hess had no quarrel with the method used to determine the pro forma unit coal cost at the Dave Johnston plant and agreed with the resulting Company coal cost estimate.

82. For the Wyodak and Bridger plants, Mr. Hess determined the pro forma coal cost by eliminating Company projections of inflation that would take place between June and December, 1981. Hess had this to say about PP&L's methodologies:

> The unit coal cost for the Bridger plant was estimated by adjusting the actual June, 1981 unit cost for 6 months of inflation forecast by Data Resources, Inc. The unit cost at Wyodak was estimated by adjusting the June, 1981 cost for 6 months of inflation assuming a continuation

> of the average increase cost experienced during the 12 months ended June, 1981. (Exh. MCC-3, P. 7)

The Bridger inflation adjustment was in the amount of $82,000 ($318,000-$236,000), according to staff computations fully explained in the Captive Coal Section of this Order.

83. To arrive at his unit coal cost for the Centralia plant, Mr. Hess used the same approach as the method used for the Dave Johnston plant for the 13 months ended June, 1981. The Company calculated the unit coal price for Centralia to be $15.10, based on data from four selected months. Mr. Hess testified the following:

> Even though the annual average is distorted by a strike at the Centralia mine in February and March of 1981, I believe the pro forma annual cost is a more reliable guide than four selected months. Consequently, for Centralia I use a unit coal cost of $13.71 per ton. (Exh. MCC-3, p. 8)

84. The Company has maintained opposition to Mr. Hess' adjustments for coal costs:

> Mr. Hess has adjusted coal costs to levels which at best represent June, 1981 costs, which are over 7 months old at the time of the hearing. The revenue requirement as determined in these proceedings for costs which are valued on a per unit basis should be set on the basis of the most current available information. This procedure is of the utmost importance if the Company is to be allowed a reasonable opportunity to earn its authorized rates of return. (Exh. PP&L 19-T, pp. 21-22)

85. Mr. James T. Watson, the Applicant's expert witness on this issue, provided the following analysis:

> The costs of coal have been steadily increasing through time. Rates based on Mr. Hess' proposed coal price levels will not provide revenues sufficient to recover expected unit coal costs during the period the rates are in effect. If the Commission adopted Mr. Hess' coal adjustment, the Company's opportunity to earn its authorized return would be even further eroded. (Exh. PP&L 19-T, pp. 22-23)

86. Concerning the concept of using current data adjusted for known and measurable changes, Mr. Watson had the following to say about Mr. Hess:

> It appears that Mr. Hess' adjustments are inconsistent with the concept of using current data adjusted for known and measurable change except as he sees it. Mr. Hess has consistently adjusted the

> Company's rate case down in significant areas even when those areas conform to the concept of current data adjusted for known and measurable changes. In areas of minor significance, postage rate increases, etc., he has chosen to follow the concept. Mr. Hess' approach is inconsistent and appears to be governed by an attempt to once again prevent the Company from earning its authorized rate of return. (Exh. PP&L 19-T, pp. 19-20)

87. Concerning the issue of adding prospective inflation to coal costs, the Commission has consistently ruled that such inflation is not a known and measurable change. In keeping with past decisions, the Commission agrees with Mr. Hess' elimination of the Company's inflation factors for the cost of coal.

88. The Commission also agrees with Mr. Hess in his use of annual average cost of coal as opposed to the concept of selecting certain months and determining average coal costs from that data. The methodology used by Mr. Hess provides a more accurate analysis of a yearly average than the Company presented. Using four selected months as a basis for a yearly average presents the possibilities of extreme subjectivity, incomplete data, and overall inaccuracies.

89. The Commission expresses a concern over the figures of Mr. Hess for the possible misconstruing of data resulting from the two-month strike at the Centralia plant. A process of normalization for that time period was conducted by the Staff with various techniques being used. The results of that analysis, however, did not provide a useful alternative.

90. Based on the testimony in this Docket and past Commission decisions, the Commission adopts the coal expense adjustments of Mr. Hess in the amount of $193,000. This figure is arrived at by the following calculation:

Total Hess Adjustment	$429,000
Less: Unaccepted Wilson Adjustment (Captive Coal)	236,000
Total Accepted Adjustment	$193,000

Sale of Tax Deductions

91. MCC witness Hess recommended the amortization of the proceeds from the sale of tax benefits. When PP&L received authorization for the sale of tax benefits, this Commission clearly indicated that the proceeds from the sale of utility assets would be subject to a ratemaking determination. The Commission is not persuaded by the Company's argument that Montana ratepayers are no worse off under its proposal than if the transaction had never occurred. The

proposal presented by Hess of amortization of the proceeds over five and thirty years appeals to the Commission as an even handed sharing of benefits between the Company and its ratepayers. The adjustment includes a decrease in expense of ($92,000) associated with investment tax credits and a decrease in expense of ($135,000) associated with accelerated cost recovery. The adjustment of ($227,000) is accepted by the Commission. A strong concern of PP&L is that future regulations from the Treasury will forbid the ratemaking treatment proposed by Hess. Should regulations be issued which indicate that the ratemaking treatment adopted by this Commission are improper, the Commission will review the matter.

Pro Forma Interest

92. In its calculation of interest expense the Company excludes interest on construction funds. MCC witness Hess seeks to include interest on construction through the use of a pro forma interest computation. The Company argues that those interest deductions should be carried to the future to offset the expense of the plant going into service. The Commission is persuaded that interest on construction is deductible for income purposes and should be included in the calculation of interest. The result of the pro forma interest adjustment is ($19,000) State Tax and ($130,000) Federal Tax.

Restoration of Unused Investment Tax Credits

93. The Company proposes to restore investment tax credits on a modified flow-through basis over an eight year period. MCC witness Hess on the other hand advocates a flow-through of one-half of the investment tax credits that can be utilized in the test year after adjustment for any rate increase authorized. The Company argues that their approach meets the goals of capital formation and passes some of the benefits to future rate payers. Hess takes the position that in an environment where net plant is always growing, there is no reason to defer the recognition of these benefits. The Commission after a careful review finds no reason to modify its treatment of investment tax credit restoral in Order No. 4771a. The amount of the approved investment tax credit adjustment is calculated to be $929,000.

94. The following revenue and expense proposals were submitted. The final column contains the present revenue and expense amounts approved by the Commission:

SCHEDULE I

Pacific Power and Light Company
Pro Forma Results of Montana Electric Operations at Present Rates
1980 Test Year

	Company	MCC Adjustment	Commission Adjustment	Accepted
Operating Revenues	$21,190	$ (54)	$ 49	$21,185
Operating Revenue Deductions				
Operating Expenses	$12,940	$(445)	$(209)	$12,731
Depreciation & Amortization	2,421	(140)		2,281
Taxes Other than Federal Income	1,437	(189)		1,248
Federal Income Taxes	--	--		--
Deferred Income Taxes	29	19		48
Income Taxes Deferred in Prior Years	(85)	--		(85)
Investment Tax Credits Deferred	--	--		--
Investment Tax Credits Restored	(26)	--		(26)
Amortization of Proceeds from Sale of Tax Deductions		(227)		(227)
Total Operating Revenue Deductions	$16,716	$(982)	$(209)	$15,970
Net Operating Revenues	$ 4,474			$ 5,215
Total Rate Base	$66,729			$65,565
Rate of Return	6.70%			7.95%

95. The Commission finds that additional annual revenues in the amount of $2,889,000 are needed by the Applicant. This amount is arrived at by adding line 1 columns (B), (C) and (D) in the following table.

SCHEDULE II

Pacific Power and Light Company
Additional Revenues Required to Produce 11.12% Rate of Return
Montana Electric Operations
1980 Test Year
(000)

A	B	C	D	E
Pro Forma	To Eliminate Negative	To Eliminate Negative	To Produce	

	Present Rates	Federal Tax	State Tax	11.12% Return	Total
Operating Revenues	$21,185	$ 199	$ 19[1]	$2,721	$24,142
Operating Expenses	12,731	1		11	12,743
Depreciation and Amortization	2,281				2,281
Taxes Other Than Income	1,248			2	1,250
State Income Tax	(37)	(13)	19	183	178
Federal Income Tax					
Before Inv. Tax Cr.	(85)	85		1,162	1,162
Inv. Tax Cr.				(929)	(929)
Net Federal Income Tax	(85)	85		233	233
Deferred Income Tax	48				48
Income Tax Deferred in Prior Years	(85)				(85)
Investment Tax Credit Adjustment					
Deferred				929	929
Restored-Current Year				(465)	(465)
Restored-Prior Years	(26)				(26)
Net Adjustment				464	438
Amortization of Proceeds from Sale of Tax Deductions	(227)				(227)
Operating Revenue Deductions	15,848	99	19	893	16,859
Net Operating Revenues	5,337	100	--	1,828	7,265
Rate Base	65,565			(232)	65,333
Rate of Return	8.14%				11.12%

E. RATE DESIGN

96. Cost of Service. The Company (Sirvaitis, Exh. 5-T) proposes a Long-Run Incremental Cost (LRIC) calculation resulting in unit LRIC and proposed class revenue responsibilities. The LRIC study is similar to that submitted in Docket No. 6728, with the exception that the study has been expanded to include the irrigation and lighting loads.

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[1] Source: MCC Opening Brief

97. The Consumer Counsel (Wilson, Exh. MCC-5) generally endorses the Company's calculations, with one exception. Dr. Wilson argues that the Company's use of marginal distribution and marginal customer costs exacerbates the revenue reconciliation requirement of marginal costing while serving no significant resource price signal function.

98. The Company's rebuttal position is that marginal costing of the bulk power supply requires marginal costing of the distribution and customer components -- otherwise entails an apples and oranges situation.

99. Although Dr. Wilson's position is well taken, the Commission accepts the Company's calculations. The costing of distribution and customer service components has been extensively debated in recent electric rate proceedings (e.g. Docket No. 80.4.2 and Docket No. 81.1.2). In accepting the Company's LRIC study, the Commission wishes to point out that the distribution/customer LRIC will be the subject of further investigation in subsequent proceedings.

100. Schedule III provides a summary of the LRIC calculations.

SCHEDULE III
Summary of LRIC Study[1]
(1981 10^3 $)

	Energy	Demand	Customer	Total	%
Residential	18,328	7,931	4,624	30,883	51.7
General Service	10,107	5,174	1,176	16,457	27.6
Large Gen. Serv.	9,099	2,535	18	11,652	19.5
Agric. Pumping	103	B[3]	150	253	.4
Lighting[2]	414	50	0	464	.8
Total	38,051	15,690	5,968	59,709	100.0

1 Sirvaitis, Exh. 5-T, Table 5-14
2 Does not include facilities-related costs
3 Included in customer

101. Class Revenue Responsibility. The Company (Sloan, Exh. 6-T) proposes to allocate authorized revenues to each customer class in direct proportion to the class LRIC provided in Schedule 1.

102. In the case of Agricultural Pumping, however, the Company proposes to deviate from the LRIC basis. The Company's costing efforts indicate a pumping rate level significantly higher than the General Service rate level. The Company maintains that it would be difficult to administer the

pumping schedule to irrigation load when the irrigator would "have a significant economic incentive to receive service on Schedule 22 (General Service)." (Exh. 6-T, p. 8)

103. The Commission finds that the Company's proposed elimination of the pumping schedule represents a step backwards in terms of costing accuracy. The Company is directed to maintain the Agricultural Pumping Schedule and to serve the Agricultural Pumping load exclusively at the resulting rate. The General Service tariff shall feature availability language which precludes the Agricultural Pumping loads.

104. However, for purposes of moderating customer impact, the Company is directed to increase the Agricultural Pumping class revenues, net of Schedule 98, by only one-half of that amount resulting from a strict application of its LRIC analysis.

105. Schedule IV provides an approximation of the resulting class revenue responsibilities.

SCHEDULE IV

Resulting Class Revenue Responsibility (10^3 $)

		Interim		Final	
	Existing[1] Revenues	Revenues[2]	Less Credit[3]	Revenues[4]	Less Credit [5]
Residential	8,216	9,574	7,717	10,001	7,793
General Service	4,209	4,858	4,834	5,329	5,301
Lg. Gen. Serv.	2,878	3,279	3,279	3,773	3,773
Agric. Pump	44	50	39	69	56
Lighting	364	389	381	357	346
Other[6]	3	3	3	15	15
Empl. Discount[7]	(32)	(38)	(38)	(39)	(39)
Total	15,682	18,115	16,215	19,501	17,242

1 Docket No. 80.8.67 (Order No. 4771a)
2 Docket Nos. 81.7.66 (Order No. 4832) and 81.8.70 (Order No. 4881)
3 Docket No. 81.9.81 (Order No. 4843a)
4 Order Nos. 4832a and 4881a
5 Order No. 4843b; trended approximation
6 Includes $12,000 revenues as a result of changes in rules and regulations
7 Trended approximation

106. Rates. The Company (Sloan, Exh. 6-T) proposes, in designating rates generating authorized revenues, to basically maintain the existing class rate structures. The Commission accepts the Company's proposal with one exception.

107. In Order No. 4667b (Docket No. 6728) the Commission directed the Company to eliminate fixed customer charges. The complying tariffs feature neither customer charges nor minimum bill provisions. The Commission finds that the tariffs should reflect minimum bill provisions and directs the Company to establish minimum bills as provided in Schedule V. With the exception of the Residential class, the minimum bill levels designated reflect the Company's "billing-related" LRIC calculations. The residential minimum was limited to $2.50 to minimize the possible promotional aspects of a minimum "take or pay" provision.

Schedule V
Minimum Bills

Residential	$ 2.50
General Service	$ 4.81
Large Gen. Service	$134.38
Agric. Pumping	$ 37.45

108. Rules and Regulations. The Company (Sloan, Exh. 6-T) proposes several revisions to the tariffed rules and regulations -- including temporary service charge, disconnect and reconnect charges, and line extension policy. The changes proposed are structured to make these services more closely priced at compensatory levels to deter abuses and, in the case of line extensions, uneconomical incidence of space heating installations.

109. The Commission approves the proposed revisions as submitted, with the exception of line extension policy.

110. Line Extension Policy. Currently the Company will construct a line extension without cost to permanent customers -- both residential and nonresidential -- as long as the total costs do not exceed twelve (12) times estimated annual revenues; the total cost of the extension shall include: meters, transformers, "reasonable overhead" and any additional costs required to rearrange existing facilities. The positive difference between the total costs of a line extension and 12 times estimated annual revenue must be advanced by the customer to the Company. An exception to this prepayment requirement may be made when the Company determines such facilities are justified by additional future load to be served, or where such excess facilities will be used for general system

improvement. Currently, underground line extensions will be made only when mutually agreed upon by the Company and customer.

111. In an attempt to arrive at a line extension policy acceptable to the Commission, both Commission staff and Company staff (Dave Sloan) communicated extensively resulting with two revisions to the Company's original proposal (David Sloan, Exh. 7 - Proposed Rates). In the following, the controversial components of the Company's two proposals are reviewed followed by the Commission's decision.

112. The Company's initial line extension policy is bifurcated between residential and nonresidential customers. For residential customers, the Company proposed to contribute to the cost of a line extension up to a ceiling of $1,200 -- the free extension allowance. Costs in excess of $1,200 must be advanced to the Company by the applicant.

113. For nonresidential applications, the Company initially proposed to construct a line extension if the applicant agreed to the following two conditions: (1) the applicant would agree to pay the amount by which the estimated cost of a line extension exceeded three (3) times the applicant's estimated annual revenue -- the nonresidential free extension allowance (FEA), and (2) "an applicant may be required to contract to pay for sixty (60) months the amount, if any, by which the contract minimum exceeds schedule billings." Where the Monthly Contract Minimum (MCM) equals:

$$MCM = 0.0167 (FEA) + 0.80 (\text{Monthly Schedule Billings})$$

Not evident from the above language, but partially clarified by communication with the Company, is that the Company intended that the applicant pay the greater of either MCM or Monthly Schedule Billings (MSB), and not the positive difference between MCM and MSB.

114. The Commission reviewed the Company's initial proposal with the following conclusions. First, regarding FEA, the Commission finds the Company's existing tariff promotional and in need of revision. The establishment of a flat $1,200 FEA for residential customers clearly reduces the promotional aspects of the existing tariff; the nonresidential FEA, while somewhat less promotional, still ties FEA to the expected level of electric consumption. Secondly, the Commission finds insufficient justification in assessing a monthly bill -- for nonresidential customers -- equal to the greater of MCM or MSB. One question that arises, with respect to MCM, is whether the FEA, in addition to being repaid by the nonresidential applicant, is also in the Company's rate base.

115. In response to staff's communication, the Company submitted a final proposal that addressed some of the Commission's concerns. This final proposal standardized the FEA in terms of the types of costs the Company would cover -- FEA -- which included the transformer, meter and service installation. In dollar terms, however, the FEA, under this proposal, is still variable. The Company made no changes to the methodology for computing a nonresidential customer's monthly bill in the final revision.

116. In order to reduce the promotional elements of the Company's existing line-extension tariff, the Commission directs the Company to adopt a FEA policy with a ceiling of $1,200 for both residential and nonresidential customers; furthermore, the monthly bill shall be equal to the MSB for each customer class, replacing the Company's proposed methodology of assessing nonresidential customers a monthly bill equal to the greater of MCM or MSB.

117. For either customer class -- residential and nonresidential -- the Commission requests that the Company institute the following policies with respect to electric line extensions: (1) inform each applicant in writing of his/her option to obtain bids and the opportunity to have a non-Company source install a line extension; (2) provide each applicant a definitive list, in writing, of estimated labor and material requirements for the applicant's line extension and (3) written notice that the Company will provide the free extension allowance -- up to $1,200 -- to any applicant regardless of whom the applicant contracts to provide the line extension; ownership of the line extension remains with the Company, however, the customer's contribution to the line extension, in excess of the Company's $1,200 free extension allowance, will be accounted for as customer contributed capital.

118. <u>Summary</u>. The Company is directed to design rates to recover the authorized revenues resulting from this Order, as well as Order Nos. 4832a and 4843b (BPA exchange credit). Class revenues are to be based on an equiproportional application of the Company's LRIC study. The Company is directed to maintain Schedule 36 -- Agricultural Pumping -- and price that service consistent with the LRIC study, but moderated per Finding No. 104.

119. As proposed, the Company is to design rates that reflect the existing rate structures, except that the tariffs are to include minimum bill provisions as provided in Finding No. 107.

120. The energy rates shall be structured to recover both energy and commitment-related revenues. The demand rates shall be structured to recover demand revenues. The energy (10%,

nondemand metered) and demand seasonal differentials and the residential blocking differentials are to be maintained at their existing levels.

121. Lastly, the Company is authorized to revise rules and regulations as proposed except in the case of line extension policy. The Company is directed to submit tariff pages reflecting line extension policy per Finding Nos. 110 through 117.

F. OTHER ISSUES

MCC's Request for an I.R.S. Ruling

122. Dr. Wilson advocates the full normalization of tax benefits associated with the Accelerated Cost Recovery System (ACRS) by recording a deferred charge for the current taxes created by accruing deferred taxes. This proposal, designated "full normalization" has been presented to the Commission in Docket Nos. 80.4.2 (Montana Power) and 80.7.52 (Montana-Dakota Utilities). In both cases the Commission directed the utilities to request revenue rulings from the I.R.S.

123. The Internal Revenue Service has issued rulings to Montana Power and Montana-Dakota Utilities on the issue of "full normalization." The rulings indicate that if the proposal is implemented the right to use accelerated depreciation will be lost. During the hearing Dr. Wilson was asked if there was any substantive difference in his proposal in the present case and the "full normalization" issue in Docket No. 80.4.2. His reply was:

> Other than this applies to a different specific piece of legislation, and the wording of the request, I would say it's very, very similar. I would also expect the IRS would have a bias in favor of anything that maximises tax benefits in this case as apparently they did in the last. (Tr. pp. 593 & 594)

124. Dr. Wilson in his answer indicates that relative to a factual issue, there has been no change in the "full normalization." The mandate for complete normalization of ACRS is abundantly clear in the provisions of the Economic Recovery Tax Act of 1981. In light of the two revenue rulings by the IRS on this issue the Commission rejects the request for a revenue ruling in this Docket.

MHD

125. In light of rising electricity rates and production costs, the Commission strongly urges Pacific Power and Light Company to consider the potential benefits of MHD. This Commission feels that the development of methods to produce electricity more cheaply and efficiently benefit both utilities and consumers. The MHD project certainly falls within the guidelines of what the Commission views as highly positive research aimed at benefiting the energy community as a whole.

126. Magnetohydrodynamics (MHD) is a process which generates electricity by passing high temperature gases obtained from combustion of coal or other fuels through a magnetic field. The process converts the energy of the hot gases directly into electricity. After passing through the MHD generator, the exhaust gases are still hot enough to be used to produce steam which can power a turbine generator, as in a conventional power plant.

127. This "double generation" capacity gives the total MHD plant the potential to significantly increase the amount of electrical energy obtained from a ton of coal. MHD would be capable of producing up to 50 percent more electricity from a ton of coal than a conventional power plant.

128. In addition, MHD plants would have environmental benefits in that they could use both Eastern or Western coal, including coal with high sulfur content, and meet current and projected environmental standards. MHD plants also would use less cooling water than conventional plants. Electricity from MHD plants would be generated at significantly lower costs than other existing power producing technologies because of the improved efficiencies and reduced fuel use.

129. The federal government has built and placed into operation two MHD testing facilities, one in Butte, Montana and another in Tullahoma, Tennessee. Both are producing data in support of the Department of Energy national MHD program. The Butte facility was completed fairly recently. It is a 50 megawatt thermal test plant intended to permit assembly of experimental components for MHD developed and fabricated elsewhere, and to collect data on the performance of these components in actual use. Electricity was generated for the first time at the Butte facility in May of 1981. Further testing and data is needed before MHD can be commercialized, but the results so far are encouraging and indicative of great potential which hopefully could be realized before the turn of the century.

130. The Commission supports the belief that investment in MHD represents a wise and prudent investment in our nation's future. MHD can help to conserve our limited natural resources,

protect our environment, reduce the economic burden on ratepayers, and promote economic growth and stability through the availability of low cost energy for industry and the public. With these overwhelming, apparent advantages in mind, the Commission strongly urges the Company to evaluate MHD in its own power planning and to take a leadership role at EPRI in garnering more serious support from its members for this advanced, non-nuclear energy technology.

CONCLUSIONS OF LAW

1. The Applicant, Pacific Power and Light, is a "public utility" within the meaning of Montana Law, Section 69-3-101, MCA. Applicant furnishes electric service to consumers in this state.

2. The Commission properly exercises jurisdiction over the Applicant's rates and operations pursuant to Sections 69-3-102 and 69-3-302, MCA.

3. The Commission has provided full and adequate public notice of all proceedings in this Docket.

4. The rate level and rate structure approved herein are just, reasonable, and not unjustly discriminatory.

ORDER

1. The Pacific Power and Light Company shall file rate schedules which reflect increased annual revenues of $2,939,000 in lieu of, rather than in addition to, interim rates. The total annual revenues of Pacific Power and Light Company will be approximately $24,124,000.

2. The increased rates authorized herein shall be effective upon the filing and approval of revised tariffs consistent with this order.

3. Rate schedules filed shall comport with all Commission determinations set forth in this Order.

4. All motions and objections not ruled upon are denied.

5. These rates are effective for electric service rendered on and after 26th day of May, 1982.

DONE AND DATED this 24th day of May, 1982, by a vote of 4 - 0.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION.

GORDON E. BOLLINGER, Chairman

JOHN B. DRISCOLL, Commissioner

HOWARD L. ELLIS, Commissioner

THOMAS J. SCHNEIDER, Commissioner

ATTEST:

Madeline L. Cottrill
Secretary

(SEAL)

NOTE: You may be entitled to judicial review of the final decision in this matter. If no Motion for Reconsideration is filed, judicial review may be obtained by filing a petition for review within thirty (30) days from the service of this order. If a Motion for Reconsideration is filed, a Commission order is final for purpose of appeal upon the entry of a ruling on that motion, or upon the passage of ten (10) days following the filing of that motion. cf. the Montana Administrative Procedure Act, esp. Sec. 2-4-702, MCA; and Commission Rules of Practice and Procedure, esp . 38.2.4806, ARM.